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Impact of large-scale hydrogen electrification and retrofitting of natural gas infrastructure on the European power system

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ABSTRACT

In this paper, we aim to analyse the impact of hydrogen production decarbonisation and electrification scenarios on the infrastructure development, generation mix, CO_2 emissions, and system costs of the European power system, considering the retrofit of the natural gas infrastructure. We define a reference scenario for the European power system in 2050 and use scenario variants to obtain additional insights by breaking down the effects of different assumptions. The scenarios were analysed using the European electricity market model COMPETES, including a proposed formulation to consider retrofitting existing natural gas networks to transport hydrogen instead of methane. According to the results, 60% of the EU's hydrogen demand is electrified, and approximately 30% of the total electricity demand will be to cover that hydrogen demand. The primary source of this electricity would be non-polluting technologies. Moreover, hydrogen flexibility significantly increases variable renewable energy investment and production, and reduces CO_2 emissions. In contrast, relying on only electricity transmission increases costs and CO_2 emissions, emphasising the importance of investing in an H_2 network through retrofitting or new pipelines. In conclusion, this paper shows that electrifying hydrogen is necessary and cost-effective to achieve the EU's objective of reducing long-term emissions.

1. Introduction

1.1. Background

The European Union (EU) aims to become carbon-neutral by 2050. This goal is at the heart of the European Green Deal and aligns with the EU's commitment to increase global climate action according to the Paris Agreement. The electrification of end-use services in the transport, residential, and industrial sectors – coupled with the decarbonisation of electricity generation – is one of the essential options for achieving CO_2 emission reduction targets and climate change mitigation [1]. The transport and residential sectors can be directly coupled to the power system by adopting electric end-use technologies, such as heat pumps in the residential sector and electric vehicles in the transport sector. Nevertheless, various energy vectors will likely play a role in decarbonising different sectors in the net-zero future. One such vector is green hydrogen, produced using renewable energy [2]. For instance, low-carbon hydrogen has been identified as a valuable energy vector for end uses where it is one of the most efficient solutions in decarbonisation, or there is no option for direct electrification, i.e., hydrogen-intensive industry, high-temperature processes, and long-distance heavy transport [3]. Furthermore, hydrogen (H_2) can be an essential long-term energy storage option in 100% renewable power systems [4].

1.2. Electrification and hydrogen

This emerging electrification trend across industrial processes, electric vehicles, heat pumps, and green H_2 production will place additional demands on the power system, requiring significant changes in its planning and operation. Previous research has demonstrated the impact on power systems of electrifying new sectors. For instance, electrification presents opportunities for flexibility, such as the bi-directional charging of electric vehicles, which can help facilitate the integration of renewable energy sources [5]. In addition, analyses by Taljegard et al. [6] for the Scandinavian countries and Germany, and Loschan et al. [7] for Austria have found that electrification of the transportation

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sector would lead to increased electricity demand, which would be met mainly by wind and thermal plants. Moreover, Gryparis et al. [8] found that electrification of vehicles will support efforts to reduce carbon emissions — but not as fast as expected, as a significant percentage of electricity generation in the EU is still based on fossil fuels. This shows the generation mix is an essential consideration to guarantee electrification leads to an actual reduction in CO_2 emissions. Although electrifying on a large scale can aid in reducing the carbon footprint of the power system up to only a certain point, it remains a crucial component of the strategy, especially with H_2 incorporation. For example, Sasanpour et al. [9] found that compared to European power systems that do not use H_2, EU Countries that incorporate H_2 can obtain a 14%–16% reduction in their total system costs. Moreover, Pietzcker et al. [10] found that electrification would help the EU power system meet its decarbonisation goals, while Lux and Pfluger [11] and also Moser et al. [12] found that electrolysis provides flexibility to the power system. These studies suggest that electrification is required for the EU power system to meet its decarbonisation goals. However, previous analyses on EU electrification did not fully consider the combined impact of demand response, heating/transport electrification, H_2 decarbonisation, and retrofitting gas networks for exclusively H_2 transport. This paper considers all of these elements, providing a combined picture with detailed insights into the EU electricity sector of 2050.

1.3. Modelling the retrofitting of natural gas networks

In light of the growing need for efficient and sustainable H_2 transportation discussed in the previous section, retrofitting natural gas networks for exclusively H_2 transport presents a viable solution [13]. Therefore, this option should be considered in the optimisation model when analysing the large-scale electrification of H_2 production. Nevertheless, some of the state-of-the-art energy planning models in the literature, such as SpineOpt [14], TIMES [15], and COMPETES [16] do not consider this option in their investment decisions. PyPSA-eu [17] recently added the retrofit as an option in their model [18]; however, it does not consider the different levels of retrofit that can be developed in a pipeline. Retrofitting the natural gas networks mainly leads to different levels of retrofit, from compressor upgrades to pipeline reinforcements [19]. Considering different levels of retrofitting costs in the optimisation model is not straightforward. One option is to formulate a set of constraints considering binary variables; however, this option leads to a Mixed-integer programming (MIP) problem, which is harder to solve in large-scale optimisations such as the European power system. Hence, there is a need for a Linear Programming (LP) formulation that includes different levels of retrofitting as an investment option. To this end, this paper proposes an LP mathematical formulation to incorporate this option, which can be adapted to any energy planning model.

1.4. Contribution

This paper addresses two gaps in the existing literature: a lack of comprehensive analysis of electrification scenarios with H_2 decarbonisation and no linear mathematical formulation for different levels of retrofitting natural gas networks for H_2 transport. Our contribution includes a detailed power system analysis for the EU and selected countries, measuring the impact of electrification on infrastructure development, generation mix, CO_2 emissions, and power system costs. We developed a reference scenario for 2050 and analysed it with an optimisation model called COMPETES, including a proposed formulation for retrofitting natural gas infrastructure for H_2 transport. Therefore, this paper aims to answer the following research questions:

- Is it possible to effectively include the retrofit of natural gas networks as an investment option in energy planning optimisation models?
- What are the impacts on the total costs and CO_2 emissions of retrofitting the existing gas infrastructure for H_2 transport in the EU by 2050?
- How do investments in new electrolysers, hydrogen transmission, and storage infrastructure impact total CO_2 emissions compared to scenarios where these investments are not made?

These questions have been comprehensively analysed and answered throughout this paper, and the results have yielded valuable insights discussed in the conclusion Section 4.

2. Method

This paper studies the impact of large-scale electrification of H_2 production in the European electricity sector using a model-based analysis designed to quantify the effect on infrastructure development, generation mix, CO_2 emissions, and power system costs. Fig. 1 shows an overview of the methodology used to achieve this purpose. First, the input data at the European level helped to define a reference scenario for 2050 (R2050); see Section 2.3. In addition, scenario variants (NoP2H2, NoH2Storage, NoH2Transmission, and NoETransmission) were analysed to obtain additional insights by breaking down the effect of different assumptions in the reference scenario. Section 3.2 describes the scenario variants in more detail. Then, all the scenarios were run in the European electricity market model (COMPETES), enhanced with a novel formulation considering the retrofitting of existing natural gas networks to carry H_2 instead of Methane. The proposed formulation for the retrofit modelling is shown in Section 2.1, while the main COMPETES features are described in Section 2.2. Finally, the most relevant outputs of the model are shown in Section 3, which also discusses the impact of H_2 electrification in COMPETES for the reference scenario and its variants.

2.1. Formulation to retrofit the natural gas network to transport only H_2

One viable techno-economical option to enable the future transport of H_2 is retrofitting the existing natural gas networks to transport only H_2. Therefore, incorporating this option in the optimisation models is vital in analysing the large-scale electrification of H_2 production. This section shows the mathematical formulations that can be included in this option in electricity market models such as COMPETES. It is worth noting that the proposed formulation is model agnostic and can be adapted to any other energy planning model.

The retrofit considers a piecewise linear cost curve to account for the investments when increasing the H_2 transport capacity in the existing network in the optimisation model. In addition, the retrofit formulation allows accounting for different levels of H_2 compression, which increase the H_2 energy transport capacity of the network. The mathematical formulation of the retrofitting modelling is as follows:

$$\overline{p}_l^{1H2} \leq \eta^1 \overline{P}_l^{CH4} \qquad \forall l \tag{1}$$

$$\overline{p}_l^{2H2} \leq \left(\eta^2 - \eta^1\right) \frac{\overline{p}_l^{1H2}}{\eta^1} \qquad \forall l \tag{2}$$

$$p_{lt}^{H2} \leq \left(\overline{P}_l^{H2} + \overline{p}_l^{1H2} + \overline{p}_l^{2H2} + \overline{p}_l^{H2}\right) \Delta t \qquad \forall l, t \tag{3}$$

Where t and l are indices for time periods and pipelines, respectively. Parameters $\overline{P}_l^{H2}$ and $\overline{P}_l^{CH4}$ are the initial installed capacities for hydrogen (H_2) and natural gas (methane, CH4), respectively; Δt is the time duration; and η^1 and η^2 are the efficiencies for the first and second H_2 retrofit, respectively. By definition, $\eta^2 > \eta^1$ since the second retrofit includes higher compression, resulting in higher energy content.

The variable $\overline{p}_l^{1H2}$ is the capacity of the first retrofit which is limited by the initial installed capacity of the natural gas pipeline $\overline{P}_l^{CH4}$ (1). The variable $\overline{p}_l^{2H2}$ is the extra capacity added to $\overline{p}_l^{1H2}$ due to higher compression and is limited by (2). Notice that if the natural gas pipeline is

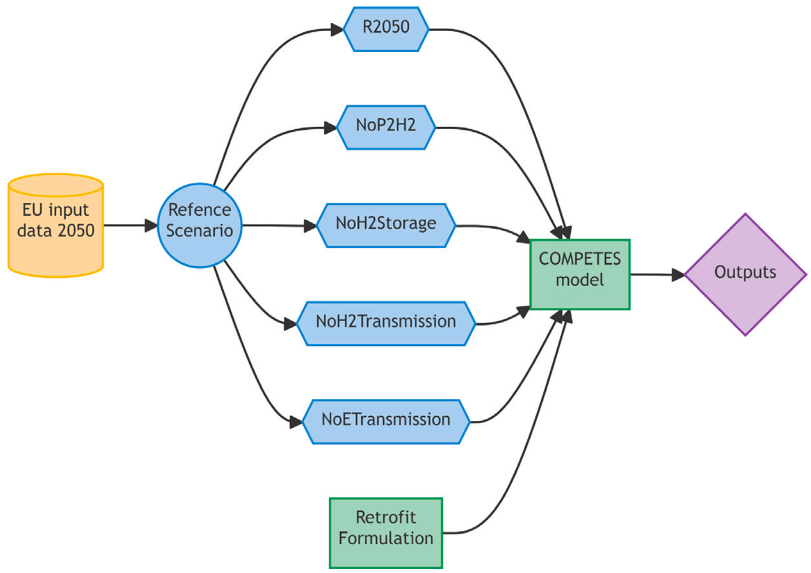

Fig. 1. Methodology overview.

completely re-purposed with the second retrofit (higher compression), $\overline{p}_l^{\text{1H2}} + \overline{p}_l^{\text{2H2}} = \eta^2 \overline{P}_l^{\text{CH4}}$.

Constraint (3) limits the H_2 flow variable p_{lt}^{H2} to the initial H_2 capacity $\overline{P}_l^{\text{H2}}$, plus the first and second retrofits $\overline{p}_l^{\text{1H2}} + \overline{p}_l^{\text{2H2}}$, plus the new H_2 capacity investment variable $\overline{p}_l^{\text{H2}}$.

The retrofitted H_2 transport capacity decreases the natural gas transport capacity:

$$p_{lt}^{\text{CH4}} \leq \left(\overline{P}_l^{\text{CH4}} - \frac{\overline{p}_l^{\text{1H2}}}{\eta^1} \right) \Delta t \qquad \forall l, t \tag{4}$$

Where p_{lt}^{CH4} is the variable for the natural gas flow. If the first retrofit takes place at its maximum potential, $\overline{p}_l^{\text{1H2}} = \eta^1 \overline{P}_l^{\text{CH4}}$ from (1), then (4) enforces that the maximum available flow capacity for natural gas is zero. Notice that (1) is not affected by the second retrofit since the first retrofit uses the initial natural gas pipeline capacity, and the second retrofit uses the same capacity but with higher energy content due to the higher H_2 compression. The non-negative constraints for all variables are also included.

$$\overline{p}_l^{\text{1H2}}, \overline{p}_l^{\text{2H2}}, \overline{p}_l^{\text{H2}} \geq 0 \tag{5}$$

$$p_{lt}^{\text{H2}}, p_{lt}^{\text{CH4}} \geq 0 \tag{6}$$

The hydrogen p_{lt}^{H2} and methane p_{lt}^{CH4} flows appear in their nodal energy balances [20]. The retrofit $\overline{p}_l^{\text{1H2}} + \overline{p}_l^{\text{2H2}}$ and investment $\overline{p}_l^{\text{H2}}$ variables appear in the objective function with their respective annualised capital expenditure (CAPEX), where the total retrofit and investment cost c^{TotH2} is given by

$$c^{\text{TotH2}} = \sum_l \left(\overline{p}_l^{\text{1H2}} C_l^{\text{1H2}} + \overline{p}_l^{\text{2H2}} \Delta C_l^{\text{2H2}} + \overline{p}_l^{\text{H2}} C_l^{\text{H2}} \right) \tag{7}$$

$$\Delta C_l^{\text{2H2}} = \frac{\eta^2 C_l^{\text{2H2}} - \eta^1 C_l^{\text{1H2}}}{\eta^2 - \eta^1} \qquad \forall l \tag{8}$$

Where C_l^{1H2}, C_l^{2H2}, and C_l^{H2} are the annualised Capex for the first-retrofit, second-retrofit, and new-pipeline H_2 investments, respectively. The parameter ΔC_l^{2H2} is the extra annualised investment cost to reach the second retrofit and is defined in (8). Fig. 2 shows the relationship between all these annualised investment costs.

The main advantage of this modelling proposal is that it effectively determines the optimal retrofitting decision while keeping the formulation linear. Therefore, the computational burden for a large-scale optimisation model is lower than for formulations using MIP approaches.

Finally, it is essential to highlight that the natural gas network usually includes multiple parallel pipelines connecting countries. Therefore, the results of this modelling proposal can be interpreted as the number of pipelines that require retrofitting for its implementation.

2.2. Optimisation model description

In order to address the research questions in Section 1, this paper uses the optimisation model COMPETES, which is a power system optimisation and economic dispatch model that seeks to meet European electricity demand at minimum social costs (i.e., maximising social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of generation units and transmission interconnections across European countries and regions.

COMPETES solves a transmission and generation capacity expansion problem to determine and analyse least-cost capacity investments with perfect competition formulated as a linear programme to optimise the system's generation capacity additions and economic dispatch.

The COMPETES model covers all EU Member States and some non-EU countries – i.e. Norway, Switzerland, the UK and the Balkan countries (grouped into a single Balkan region) – including a representation of the cross-border electricity transmission capacities interconnecting these European countries and regions; see Fig. 3. The model runs hourly, i.e., optimising the European power system over 8760 h per year.

Over the past two decades, COMPETES has been used for several assignments and studies on the Dutch and European electricity markets. In addition, it is used and regularly updated as part of the energy modelling framework for the annual Climate and Energy Outlook of the Netherlands; see, for instance, PBL et al. [21]. For each scenario year, the primary inputs of COMPETES include parameters regarding the following features:

- Electricity demand across all European countries/regions, including inelastic demand and additional demand due to further sectoral electrification of the energy system employing power-to-x technologies;
- Generation technologies, transmission interconnections, and flexibility options, including their techno-economic characteristics;
- Hourly profiles of various electricity demand categories and renewable energy technologies (notably hydro and variable renewable energy (VRE) sources such as solar and wind), including the full-load hours of these technologies;

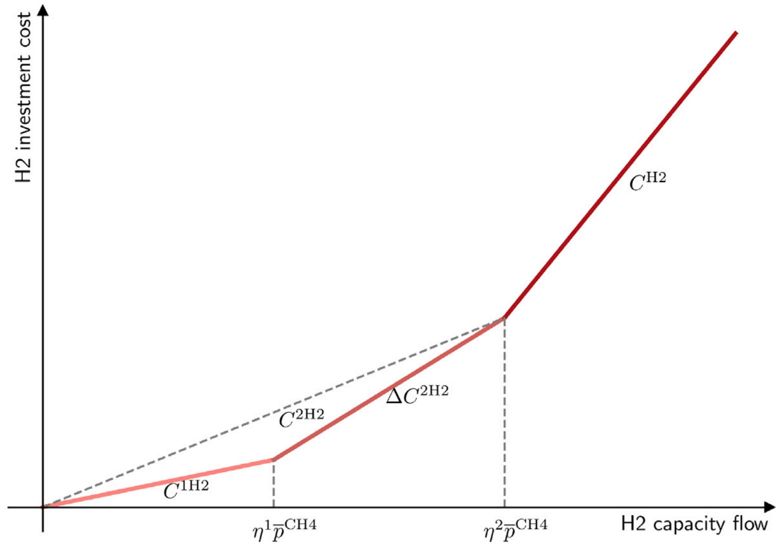

Fig. 2. H_2 retrofit and investment cost.

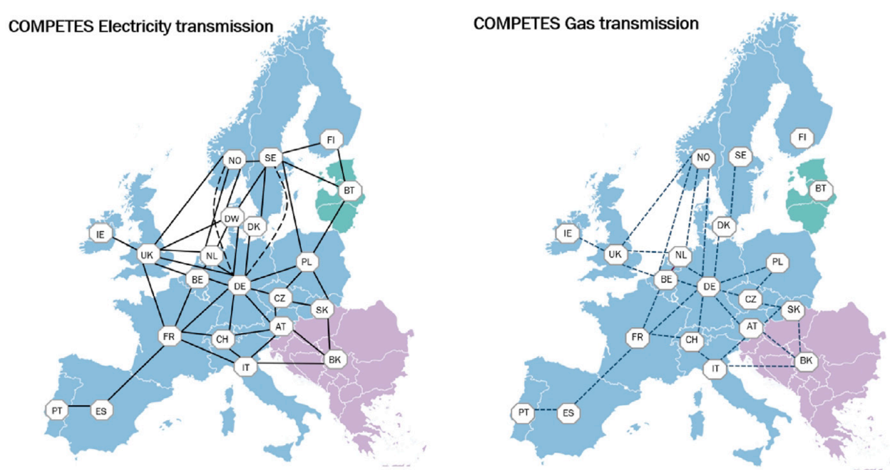

Fig. 3. The geographical coverage of the COMPETES model.

- Expected future fuel and CO_2 prices;
- Policy targets/restrictions, such as meeting specific renewable energy or greenhouse gas (GHG) targets, or prohibiting the use of certain technologies, such as coal, nuclear, or Carbon Capture and Storage (CCS).

As indicated above, COMPETES includes a variety of flexibility options. More specifically, these options include:

- Flexible generation: Conventional (gas, coal, nuclear) and renewable (curtailment of solar/wind);
- Cross-border electricity and H_2 trade;
- Demand response: Power-to-Mobility (P2M): electric vehicles (EVs), including grid-to-vehicle (G2V) and vehicle-to-grid (V2G); Power-to-Heat (P2H): industrial (hybrid) boilers and household (all-electric) heat pumps; Power-to-Gas (P2G), notably power-to-Hydrogen (P2H2);
- Storage: Pumped hydro (EU level), Compressed air (CAES/AA-CAES), Batteries (EVs, Li-ion, Lead–acid, Vanadium Redox), Underground storage of P2H2.

See Sijm et al. [16] and Özdemir et al. [22] for a more detailed description of the COMPETES model. The explicit mathematical formulation of the optimisation model in COMPETES is available in Özdemir et al. [23]. It is important to note that the ramping constraints were not considered in this study for the sake of simplicity. However, the optimisation model does include demand response modelling based on the proposed formulation by Morales-España et al. [24]. In addition, a novel mathematical formulation to model the retrofit of the natural gas infrastructure to transport exclusively H_2 is included, as shown in Section 2.1. The enhanced version of the optimisation model allows a broader perspective on the possibilities of integrating H_2 in the 2050 reference scenario and its variants. The main scenario input parameters used for these scenarios are shown in the following Section 2.3.

2.3. Reference scenario

In this section, we will discuss the supply and demand components for the 2050 European reference scenario and its variations. It is important to note that we specifically focus on modelling the electricity sector and other sectors which can potentially be electrified, such as transport, heat, and specifically H_2. However, the scenario does not consider the other potential uses of the natural gas sector in that year. This analysis assumes that the current natural gas network will be retrofitted to transport only H_2 or to meet any remaining natural gas demands.

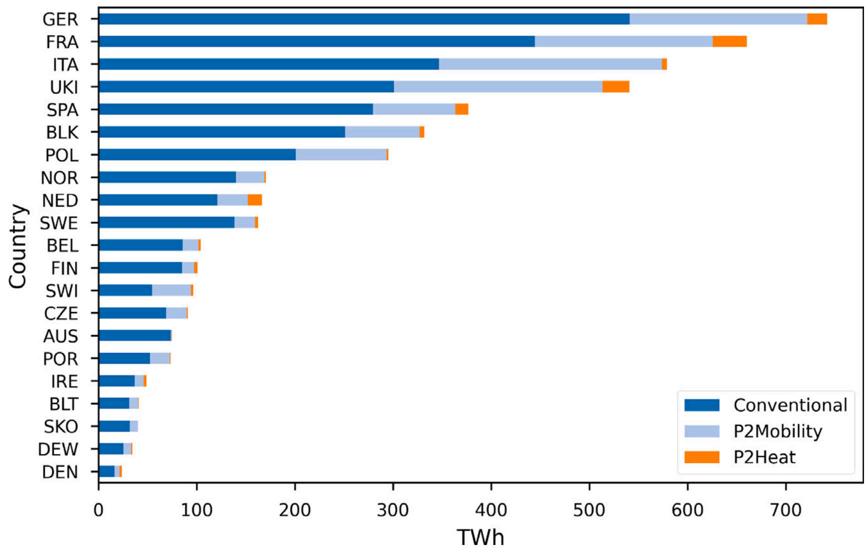

Fig. 4. EU electricity demand per country.

2.3.1. Electricity demand

Fig. 4 provides an overview of the electricity demand parameters used in COMPETES for the EU countries in the reference scenario, referred to as 'R2050'. In this figure, the electricity demand is divided into three categories: Conventional, Power-to-Mobility, and Power-to-heat. The input parameters for the conventional demand category are incorporated into the model. Conversely, the model determines the Power-to-Mobility and Power-to-heat categories' final values endogenously. Below, there is additional information regarding each category.

- Conventional electricity demand — For the R2050 scenario, the figures assume that the traditional demand for electricity consumption growth is offset more or less equally by the energy efficiency improvements. The hourly profile and demand per country are based on historical demand values [25].
- Power-to-Mobility – this demand for electric passenger vehicles (EVs) is assumed to be flexible to a certain extent. This demand includes both directions – i.e. grid-to-vehicle (G2V) and vehicle-to-grid (V2G). The projections on EV passenger vehicles are based on ENTSO-E [25] and den Ouden et al. [26]. In addition, the EVs flexibility is endogenously considered in the model based on the modelling shown in Morales-España et al. [24].
- Power-to-heat by households — This demand comes from electric heat pumps; similar to EVs, this demand is assumed to be flexible and determined endogenously using the formulation proposed in Morales-España et al. [24]. A set of constraints limits the flexibility of the heat pump. The projections on household heat pumps are based on ENTSO-E [25] and den Ouden et al. [26].

2.3.2. Hydrogen demand

The H_2 demand is based on one of the eight scenarios from the European Commission's long-term strategy to reduce greenhouse gas. *The Commission's analysis is based on the PRIMES, GAINS, GLOBIOM model suite and explores eight economy-wide scenarios to achieve different levels of ambition for 2050, covering the potential range of reduction needed in the EU to contribute to the Paris Agreement's temperature objectives of between the well below 2 °C and to pursue efforts to limit to 1.5 °C temperature change* [27]. The selected scenario, '1.5TECH' described in EC [27], focuses on technical solutions to achieve net-zero GHG emissions. It increases CCS and uses E-gases and E-fuels based on air-capture or biogenic CO_2 to further reduce emissions. The scenario also applies negative emission technologies via biomass coupled with CCS and the storage of biogenic CO_2. Fig. 5 shows the H_2 demand per EU country and for different activities within the industrial sector.

Table 1
Techno-economic input parameters for H_2 technologies.

Technology	SMR	SMR CCS 54	SMR CCS 89	Electrolyser
Source (X)	Gas	Gas	Gas	Power
2use (2Y)	H_2	H_2	H_2	H_2
Capex [€/kW]	744	881	1330	600
Fixed O&M [€/kW/yr]	27	44	62	20
LifeTime [Years]	25	25	25	30
Efficiency [p u]	0.76	0.74	0.69	0.68
Emissions [kg/MWh]	229	105	26	0
CCS [kg/MWh]	–	124	204	–

2.3.3. Energy supply: sources and technologies

COMPETES uses its investment module to meet the demand of the different energy vectors, i.e. electricity and H_2, in a cost-optimal way. COMPETES includes a variety of primary energy sources and technologies and energy conversion technologies. These technologies are described in Section 2.2. Fig. 6 shows the initial electricity generation capacities in the COMPETES model. These initial capacities serve as an input for the model, which will help to determine the new required capacity to meet the 2050 electricity and H_2 demand. These initial input values are based on the National Trends scenario [28].

2.3.4. Hydrogen generation

Similar to electricity generation, initial H_2 generation values are defined exogenously in the model. The H_2 generation technologies in COMPETES are steam-methane reforming (SMR), SMR with a 54% CCS rate (SMR CCS 54), SMR with an 89% CCS rate (SMR CCS 89), and electrolysers. Table 1 displays the techno-economic parameters that were taken into account for the H_2 generation technologies. Among the available options for electrolysers, alkaline electrolysis (AE) and proton-exchange membrane (PEM) electrolysis are the leading technologies. PEM has advantages like a faster ramping rate and is projected to become more cost-effective in the future, as explained in Böhm et al. [29]. As stated in Section 2.2, the COMPETES model does not take into account ramping constraints for the sake of simplicity. As a result, the electrolyser technology listed in Table 1 can serve as a representation of both types of technologies based on the CAPEX and Fixed O&M assumptions, as the difference in efficiency is minimal in the year 2050 [29].

Table 2 presents the initial H_2 generation output capacities assumed in this study. These are based on Maisonnier et al. [30] and Sanders

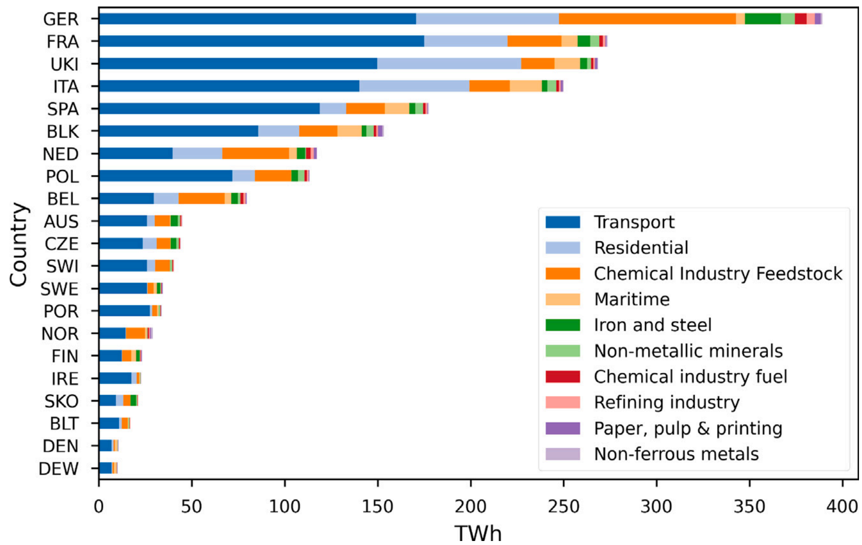

Fig. 5. EU H_2 demand per country and sector.

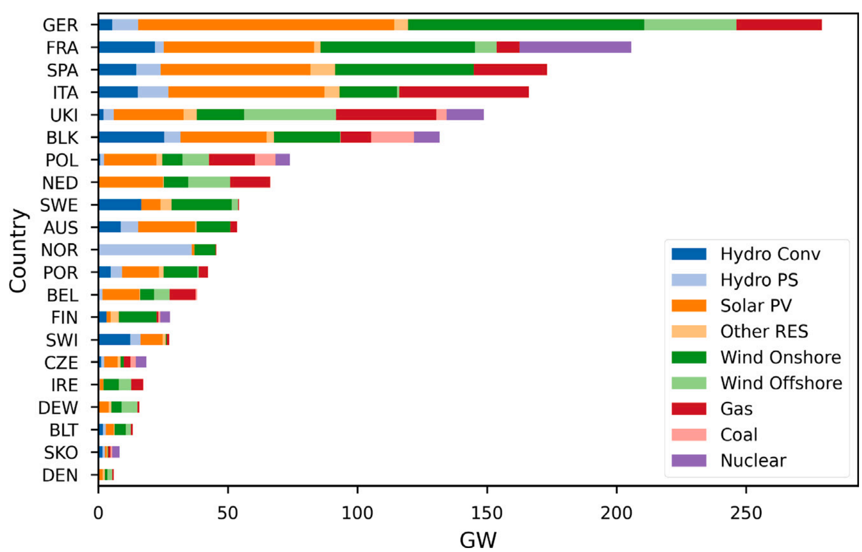

Fig. 6. Initial installed capacities per country.

et al. [31]. It is worth noting that the latest published ambitions of the European countries are higher than these values.

2.3.5. Hydrogen transport

COMPETES recently introduced the possibility of investing in H_2 pipelines for long-distance, high-volume H_2 transport between European countries, considering a transport model. Fig. 3 shows the existing natural gas transport links, which can be repurposed to deliver H_2 instead of natural gas. Also, the model can invest in new H_2 pipelines. The following decisions can be made endogenously by the model: invest in new H_2 pipelines, retrofit to 60% of initial gas capacity, retrofit to 80% of initial gas capacity (more expensive than 60% due to extra compression needed). Moreover, the modelling assumptions include:

- Retrofit and investment decisions are only possible where there is an existing pipeline.
- Transport capacities are assumed to be bidirectional, e.g. assume that gas trading capacity between Germany and the Netherlands is different depending on the trade direction. In these cases, we consider the highest capacity for both directions.
- Neither losses in transport nor variable costs for compression are considered in this study. for this study. Future research conducting a more in-depth analysis of the impacts of pressures and compression losses may offer valuable and informative perspectives on this subject.
- In the H_2 sector, decision variables are used every six hours, while the power system variables are decided upon hourly. This temporal difference in the variables' definition allows the model to account for the storage and time-shifting of H_2 through pipelines in a simplified way.
- Pipelines can be retrofitted partially since the model is only able to make continuous investment decisions.

Furthermore, it is assumed that SMR can supply a maximum of 50% of the H_2 demand of a country; this is enforced with a constraint in COMPETES. This is based on the RED II revision proposal [32], which sets a binding 50%[1] target for renewable fuels of non-biological origin used as feedstock or energy carriers.

[1] The European Commission has recently increased its target to 70% by 2035, according to the REPowerEU plan.

Table 2
Initial H_2 output capacities.

Country	Electrolyser [MW]	SMR [MW]
GER	1000	1900
FRA	6500	530
UKI	5000	144
SPA	4000	554
NED	3000	1144
POR	2000	25
AUS	0	90
BEL	0	783
SWI	0	28
CZE	0	141
DEN	0	29.5
DEW	0	29.5
FIN	0	413
BLK	0	523
IRE	0	0
ITA	0	411
NOR	0	0
SWE	0	0
SKO	0	115
POL	0	0
BLT	0	221

Table 3
Fuel prices.

Fuel	Price 2050 [€2015/GJ]
Oil	10.63
Biomass	9.00
Natural Gas	7.54
Coke Oven Gas	7.54
Coal	2.25
Lignite	1.10
Nuclear	0.78

The natural gas transmission network consists of multiple parallel pipelines. Therefore, the results for H_2 transport in this paper can be interpreted as the number of pipelines that require retrofitting for H_2 transportation instead of natural gas.

2.3.6. *Fuel and CO_2 prices*

Table 3 shows the fuel prices taken from Refs. PBL et al. [21],den Ouden et al. [26]. The CO_2 price was considered as 250 €/ton. It is important to highlight that if natural gas prices increase beyond what is listed in this table, it could encourage the electricity sector to produce more H_2 using renewable energy sources.

2.3.7. *Carbon capture and storage (CCS)*

COMPETES endogenously optimises the investments in electricity and H_2 generation units with carbon dioxide capture and storage (CCS), such as: Biomass plants with CCS, gas CCGT plants with CCS, coal-fired plants with CCS, SMR CCS 54, and SMR CCS 89.

Importantly, CO_2 geological storage is currently prohibited in some countries. This study uses current national legislations and regulations to determine whether the model can invest in the aforementioned technologies. Based on the EU Directive 2009/31/EC on the geological storage of CO_2 [33]: Germany, Austria, Estonia, Latvia, Lithuania, Denmark, Finland, and Ireland do not allow CO_2 geological storage.

3. Results of the impact of H_2 electrification

3.1. *Reference scenario and the impact of H_2 electrification*

This section provides the main results of the reference scenario described in Section 2.3 and the impact of H_2 electrification. To measure the effect of H_2 electrification, the reference scenario R2050 is compared with scenario NoP2H2, where electrolysis is not allowed, i.e., all H_2 demand must be supplied via SMR (except for the initial electrolysers installed capacity).

Table 4
H_2 supply in R2050 and NoP2H2 [TWh].

Country	Scenario	Electrolyser	SMR CCS 54	SMR CCS 89	Net import
NED	R2050	23	2	57	0
NED	NoP2H2	9	1	417	−310
GER	R2050	75	5	0	193
GER	NoP2H2	30	2	0	363
AUS	R2050	29	0	0	21
AUS	NoP2H2	0	0	0	45
FRA	R2050	348	1	136	−83
FRA	NoP2H2	25	1	251	−3
UKI	R2050	69	0	134	1
UKI	NoP2H2	17	0	273	−22
SPA	R2050	160	1	88	−27
SPA	NoP2H2	16	1	159	2

Fig. 7 shows the H_2 supply sources for both scenarios, where the reference scenario R2050 electrifies 58% of the total H_2 demand, and the remaining 42% is supplied via SMR. The SMR technology that dominates is SMR with CCS with an 89% CO_2 capture rate (SMR CCS 89) due to the CO_2 price of 250 €/ton. Notice that 5% of the H_2 demand in NoP2H2 is provided by electrolysis, which results from the initially installed capacities of electrolysers. Similarly, the model uses existing SMR without CCS facilities to supply 4% and 2% of the H_2 demand in R2050 and NoP2H2, respectively.

Fig. 8 shows the total installed capacities for H_2 supply. Notice that the total H_2 installed capacity of R2050 increases 48% compared to NoP2H2. This capacity oversize in the R2050 is caused by the investment in electrolysers, which requires the installation of approximately 250 GW capacity in the EU for the year 2050. This result suggests that it is more economically efficient to invest in a larger capacity to produce more H_2 during periods with low electricity prices (VRE-dominated production) and store it for later use, thus avoiding producing H_2 during high electricity prices. Electrolysers present 4900 Full Load Hours (FLH) in R2050, whereas SMR operates 7500 FLH in R2050 and 8650 FLH in NoP2H2.

Table 4 shows how the H_2 is supplied in different countries via SMR, electrolysis, or imports. One can observe three different types of countries:

1. Countries with very high VRE production, like France and Spain, which shift most of their H_2 production from SMR in NoP2H2 to electrolysis in R2050, and even become net exporters.
2. countries that still find SMR as the most economical way to produce H_2 (e.g., because of low VRE potentials), which use their maximum allowed SMR production, 50% of the internal demand, and supply the remaining H_2 demand via electrolysis and imports, even moving from a net export position in NoP2H2 to a net import position; this is the case for countries like the Netherlands and the UK.
3. Countries that do not allow carbon storage, which supply H_2 mainly through imports and electrolysis, e.g., Germany and Austria.

The 58% level of H_2 electrification requires almost 1841 TWh,[2] of extra electricity demand, accounting for nearly 28% of the total electricity demand in 2050. See Fig. 9 which shows the electrical energy mix for both scenarios R2050 and NoP2H2. To meet the new H_2 electrical demand, the system uses and invests mainly in more solar PV, wind offshore, and wind onshore; see Fig. 10. The total VRE production changes from 3316 TWh in NoP2H2 to 4952 TWh in R2050. This VRE

[2] The EU total electricity demand in 2021 was 2865 TWh.

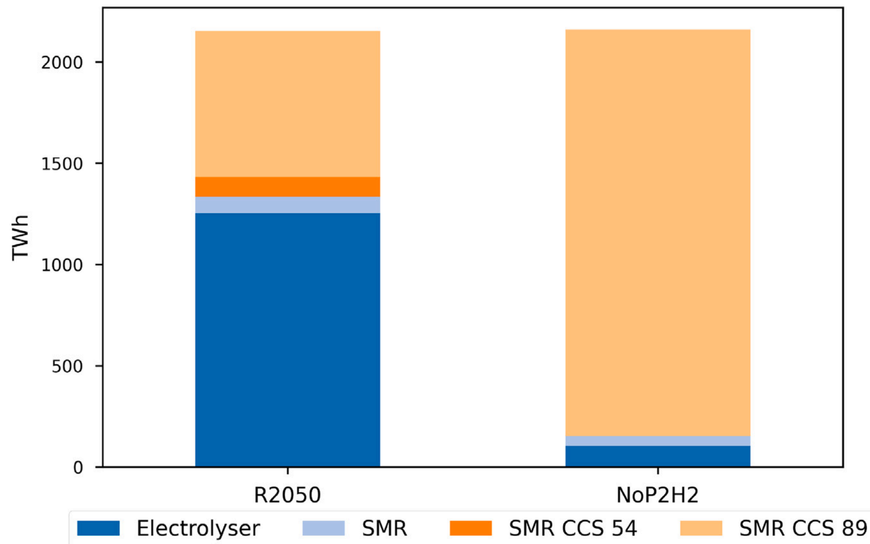

Fig. 7. EU H_2 supply in R2050 and NoP2H2.

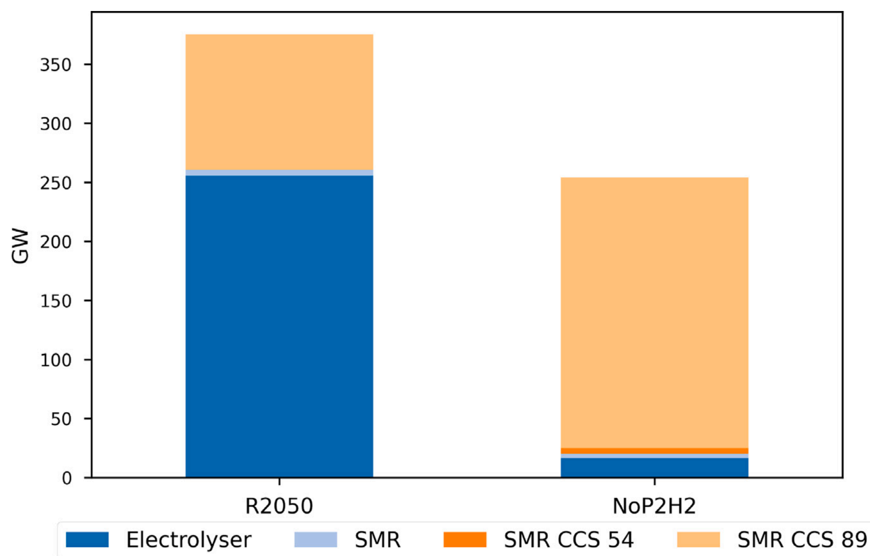

Fig. 8. EU H_2 output capacity in R2050 and NoP2H2.

production increase is equivalent to 90% of the extra H_2 electricity demand. Nuclear production also increases from 463 TWh to 789 TWh, equalling 18% of the additional H_2 electrical demand. The production of non-polluting technologies, VRE and nuclear, coveres the extra H_2 demand and even replaces part of the gas production, which decreases from 295 TWh in NoP2H2 to 93 TWh in R2050. This reduction of almost 70% in gas production appears due to the flexibility offered by the electrolysers through shifting in time (storage) and shifting source (to SMR), where electrolysis increases when electricity prices are low (e.g., due to VRE abundance). This allows the new VRE and nuclear investments to be better used, and when electricity prices are high (e.g., due to production of gas-fired power plants) electrolysis may not be viable. However, the extra investment in VRE and nuclear is still present, thus replacing gas sources.

Fig. 10 shows that there is significant increase of VRE capacity to cover the new H_2 electrification in R2050. Moreover, the flexibility of electrolysers allows for relying less on peak units. For instance, the installed capacity of gas-CCS power plants reduces from 58 GW in NoP2H2 to 6.50 GW in R2050.

Note that although some countries do not allow carbon storage, they still import H_2, which is mainly produced via SMR with CCS in NoP2H2. Some of these countries even use this SMR-generated H_2 to generate electricity — as is the case for Germany, producing 3 TWh via H_2-2-power–as shown in Figs. 11 and 12. Furthermore, it is possible that even in the case of R2050, these countries still import H_2 that is produced with SMR with CCS; once the H_2 is produced and injected into a pipeline, it is not possible to know if some given molecules of H_2 were produced via electrolysis or SMR. Figs. 11 and 12 also show how the demand and supply of electricity are divided within different EU countries. As expected, the countries with the highest electrolysis also have the highest VRE production. For example, France, Spain, and Germany, with electrolysis demand increases of 198 TWh, 127 TWh, and 249 TWh, saw increases in VRE production of 398 TWh, 138 TWh, and 170 TWh, respectively, in R2050 compared to NoP2H2.

Table 5 shows the new electricity and H_2 transmission investments for R2050 and NoP2H2. Interestingly, R2050 requires almost a 45% lower electricity transmission capacity, even though its electricity demand is 35% higher than NoP2H2. This is caused by the flexibility

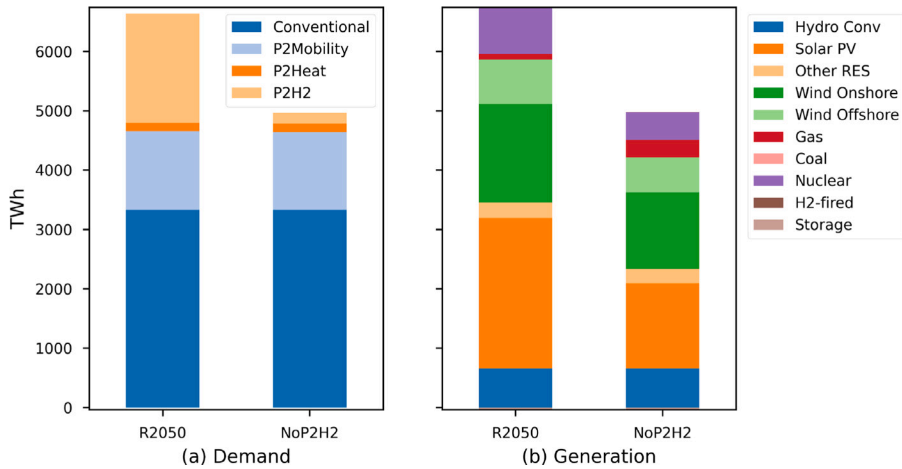

Fig. 9. EU electricity demand and supply in R2050 and NoP2H2.

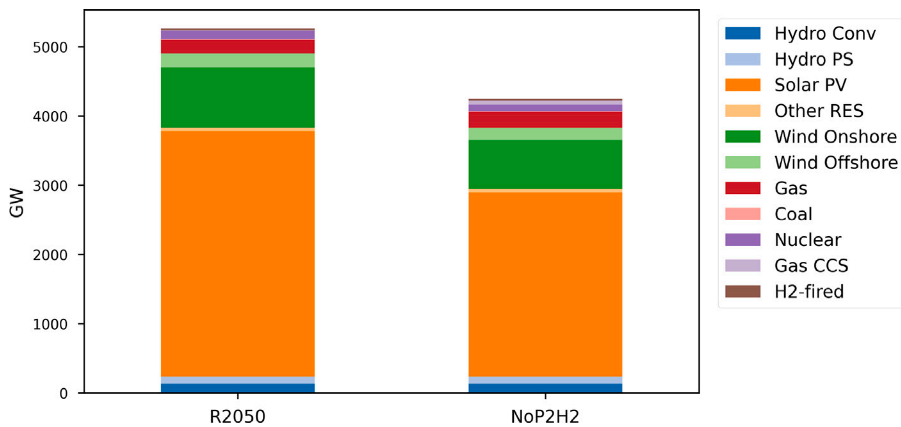

Fig. 10. EU Generation capacity in R2050 and NoP2H2.

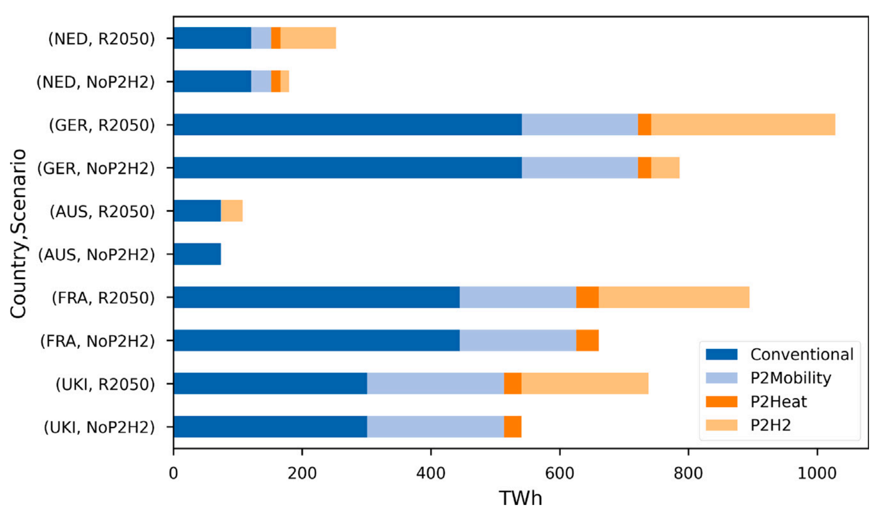

Fig. 11. NED, GER, AUS, FRA, UKI and SPA electricity.

offered by the electrolysers, where the H_2 electrification helps the system rely less on other sources of flexibility, such as electricity trade and peak units. Fig. 13 shows this general pattern of higher electricity trade in R2050; countries presenting VRE abundance trade more, as is the case of Portugal and Spain exporting more to France, where Portugal changes from being a net importer in NoP2H2 to a net exporter in R2050. Another country that becomes a net exporter is the Netherlands, not only because of its extra VRE production, but also its extra nuclear production; see Fig. 12.

The H_2 transmission capacity is 1.6x higher in R2050 (see Table 5), resulting in different trade patterns compared to NoP2H2; see Fig. 14. This is a natural consequence of countries with higher VRE investments and generation, producing (and exporting) H_2 from electrolysis. For example, France, Spain, and Norway (with high solar and wind) export

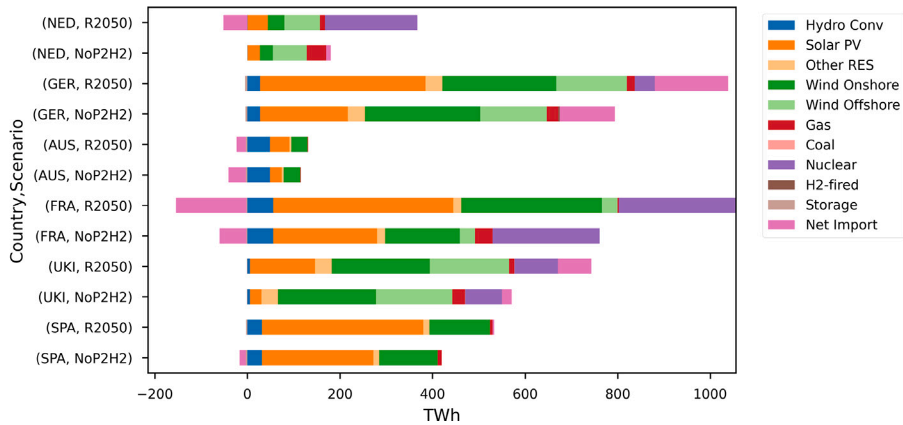

Fig. 12. NED, GER, AUS, FRA, UKI and SPA electricity.

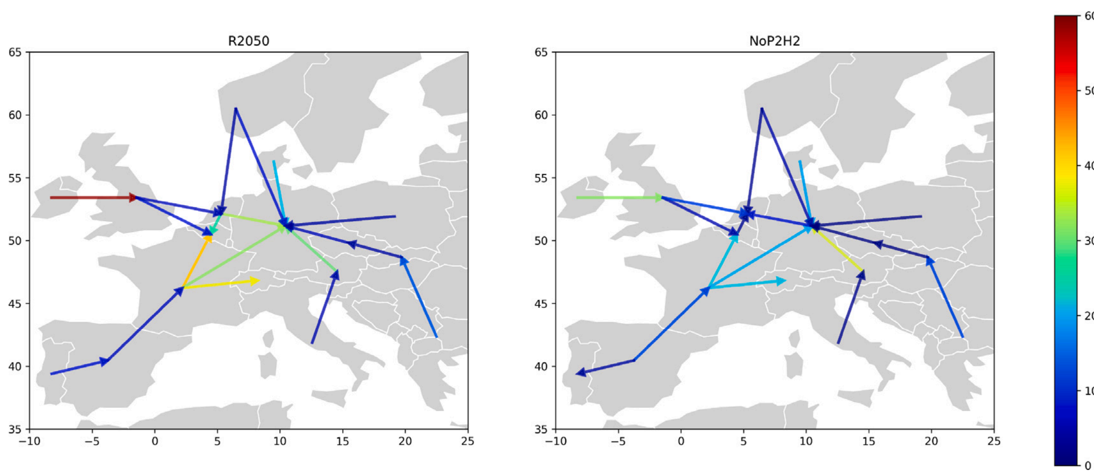

Fig. 13. Electricity net trade patterns [TWh].

Table 5
EU electricity and H_2 transmission investments in R2050 and NoP2H2.

[GW]	E-transmission	H_2 Transmission
R2050	28	90
NoP2H2	52	56

more H_2 to Germany (which has high import demand due to CCS facilities not being allowed). Ireland also supplies the UK with higher offshore wind. The Netherlands shows a less significant trade volume change with Germany due to the 50% SMR production restriction policy.

The current gas infrastructure already offers enough potential to accommodate the need for H_2 trade. Fig. 15 shows the different H_2 transmission investments between countries where no new pipelines were built and 11% of the existing gas infrastructure's total capacity was retrofitted for H_2 transportation. Although we did not model gas (methane) transportation, the remaining transport capacity (89%) is enough to accommodate 2050 requirements, which will be lower than current requirements. The NoP2H2 scenario only needed to retrofit 7% of the gas infrastructure's total capacity due to the lower need for H_2 trade.

The total CO_2 emissions of the system decreased from 106 Mton in NoP2H2 to 68 Mton in R2050. This 35% emissions reduction results from shifting 58% of the H_2 production from SMR, in NoP2H2, to electrolysis, in R2050, where mainly non-pollutive (VRE and nuclear) technologies supply the electricity for electrolysis. Even though the power system has additional demand, its CO_2 emissions are lower in R2050 since non-polluting technologies are also replacing part of the gas-fired technologies that were present in NoP2H2. As shown in Fig. 16, the CO_2 emissions in the electricity sector decreased from 44 Mton in NoP2H2, to 42 Mton in R2050. In short, electrifying part of the H_2 demand lowers emissions in the H_2 sector and helps the electricity sector reduce its emissions. This is because flexible electrolysis helps to accommodate non-pollutive production into the electric system more efficiently.

Fig. 17 shows the total system cost for R2050 and NoP2H2. Interestingly, although the total costs between the two scenarios are similar (R2050 being 0.4% lower), there is a significant redistribution of costs and R2050 yields 35% lower emissions; see Fig. 15. As expected, R2050 shows significantly higher investments in P2H2 and VRE, while incurring significantly lower SMR (investment and variable) costs and variable generation costs.

3.2. Scenario variants

Table 6 presents different variants of the reference scenario R2050. By comparing these variants, we can separate the effect of other aspects on the system: variant NoP2H2 does not allow P2H2, thus showing the impact of electrifying H_2 demand, as widely discussed in the previous section, and some results are shown again here for the sake of completeness. The variant NoH2Storage variant allows us to observe the effect of H_2 flexibility through storage (i.e., time shifting), by not allowing investment in H_2 storage. Forcing the countries to only import/export energy via electricity in variant NoH2Transmission highlights the impact of H_2 transmission. The last scenario variant, NoETransmission,

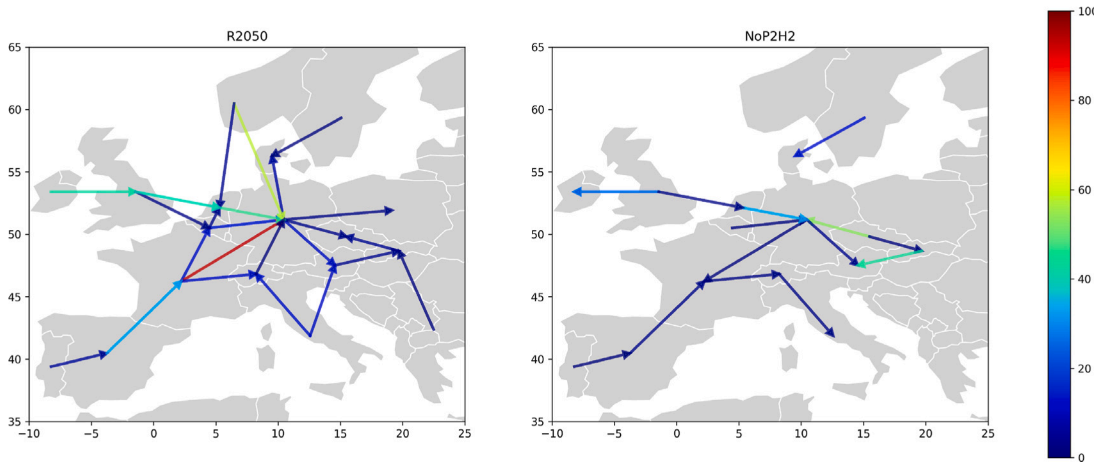

Fig. 14. H_2 net trade patterns [TWh].

Table 6
Scenario variants.

Scenario variants	Power-2-H_2 (electrolysis)	H_2 storage	H_2 transmission retrofit and new pipelines	Electrical transmission[a]
R2050	✓	✓	✓	✓
NoP2H2	X	✓	✓	✓
NoH2Storage	✓	X	✓	✓
NoH2Transmission	✓	✓	X	✓
NoETransmission	✓	✓	✓	X

[a] Existing and forecasted initial electrical infrastructure is utilised from ENTSO-E [28].

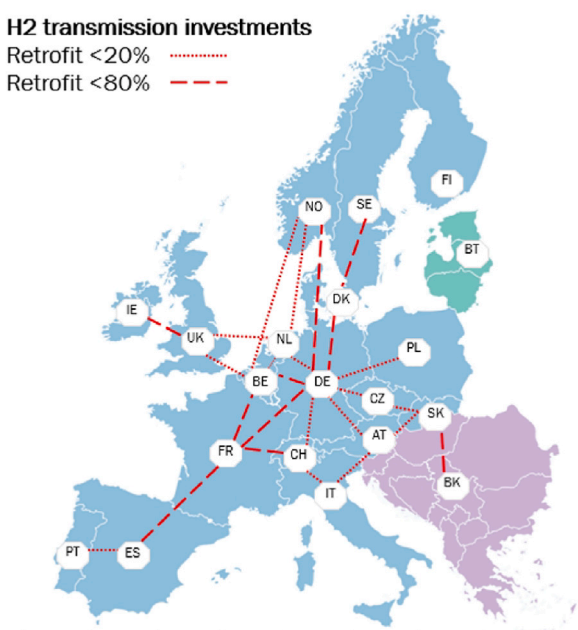

Fig. 15. EU H_2 transmission investments map in R2050.

does not allow new expansions in the electricity network, thus only using the forecasted electricity transfer capacities; this previous variant analyses how investing in a H_2 network compares to expanding the current electricity network.

3.2.1. H_2 *supply and storage*

Fig. 18 presents the H_2 balances across various scenario variants at the EU level. The results indicate that in the R2050, NoH2Storage, NoH2Transmission and NoETransmission scenarios, the demand for electrified H_2 ranges from 58% to 61%. Notably, it is still optimal to satisfy approximately 40% of the total H_2 demand through SMR technology with 89% of carbon capture, even at a high CO_2 price of 250 €/ton. Furthermore, the policy limit of up to 50% SMR generation is not reached at the EU level.

In the NoH2Storage variant, SMR with 54% CO_2 capture appears viable in some countries. However, this option only meets 5% of the total H_2 demand and the SMR technology with 89% CO_2 capture is the preferred choice across all variants.

The NoH2Transmission variant exhibits the highest production of SMR without CCS, producing 97 TWh of H_2. Moreover, 80% of this H_2 is produced by Germany, which is not allowed to invest in CCS technologies and cannot import H_2 from other countries.

Fig. 19 displays the underground H_2 storage investments for the scenario variants relative to the reference scenario R2050. The following key observations can be made from the results. First, the underground H_2 storage requirement reduces significantly when there is no electrification of the H_2 demand. Specifically, in the NoP2H2 scenario, 58.4 TWh less storage is required compared to the R2050 scenario. The constant H_2 supply from SMR eliminates the need for time-shifting VRE-based H_2. Second, in the NoH2Transmission scenario, where H_2 transmission is not allowed, there is a 12% increase (9.2 TWh) in H_2 storage requirements compared to the R2050 scenario. This increase is due to the higher need for time-shifting of H_2 to compensate for the flexibility lost from geographical shifting.

3.2.2. *Electricity supply and demand*

Figs. 20 and 21 compare the EU electricity demand and supply of the scenario variants to the reference scenario R2050. The results show that the H_2 electrical demand is similar for the scenarios R2050, NoH2Storage, and NoH2Transmission, with only a 3 TWh difference. This marginal demand change can be attributed to the system's ability to use spatial or temporal flexibility to achieve similar levels of H_2 electrification. In addition, the H_2 electrification levels and energy

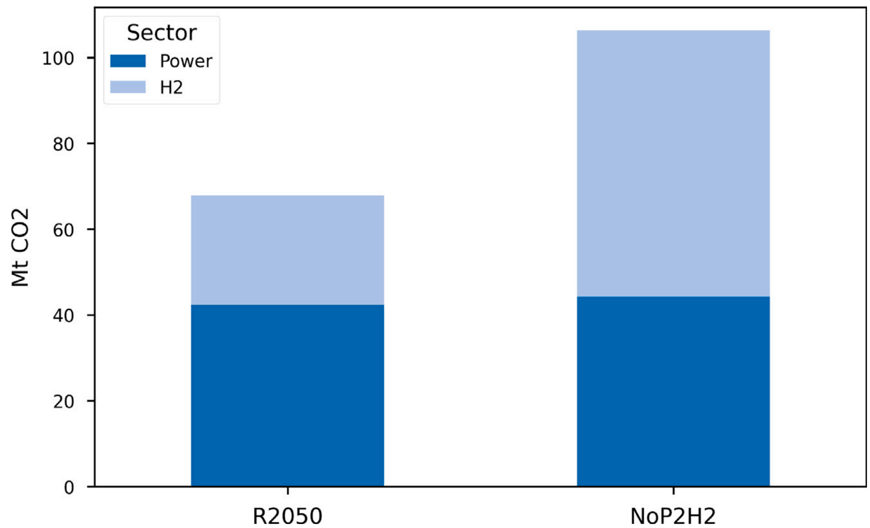

Fig. 16. EU CO_2 emissions for the electricity.

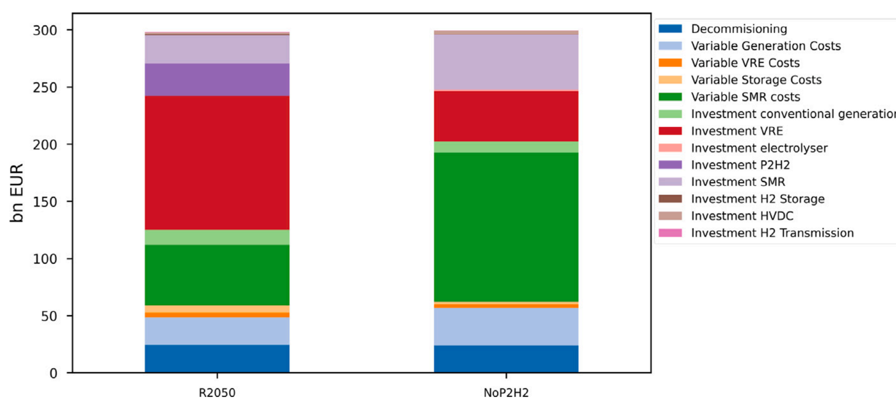

Fig. 17. EU total system costs in R2050 and NoP2H2.

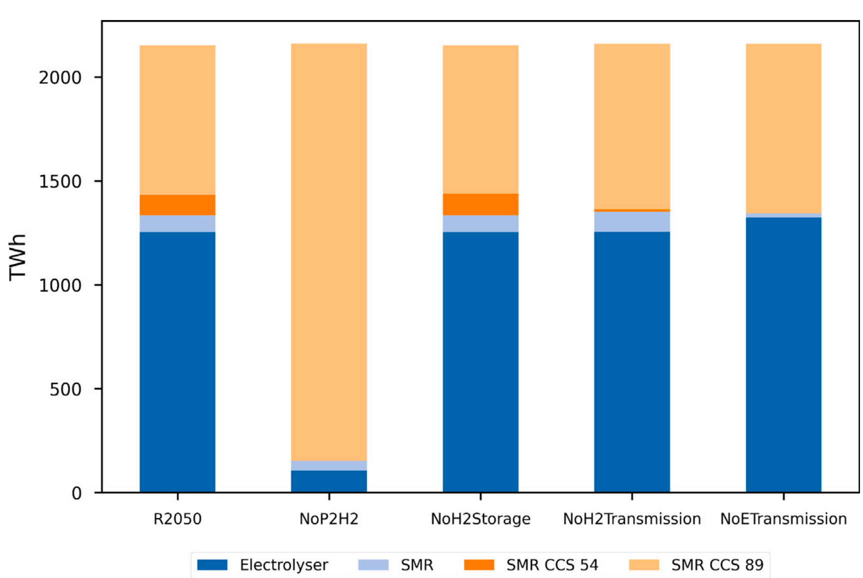

Fig. 18. EU H_2 generation — comparison of R2050 and scenario variants.

mixes are similar for the R2050 and NoETransmission scenarios, suggesting that a system with the expected transmission expansion by 2050 is already near the optimal solution. Finally, in comparison to R2050, the H_2 electrification levels are similar in the NoH2Storage and

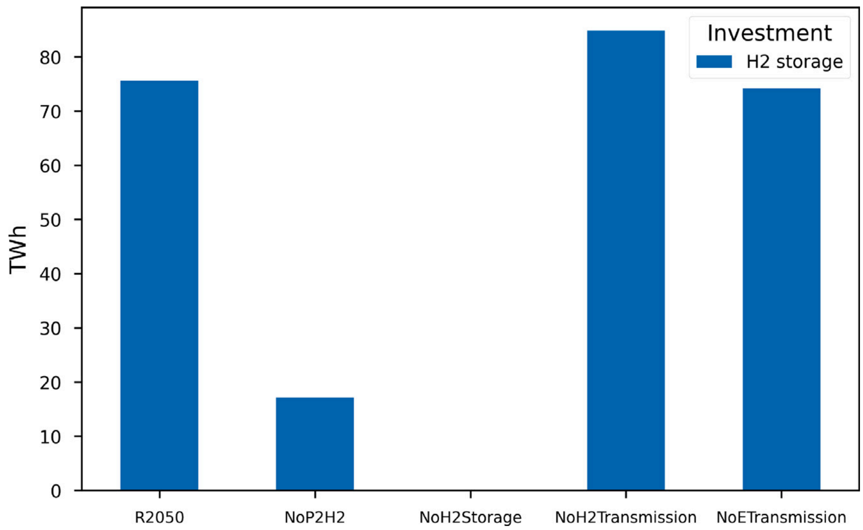

Fig. 19. EU H_2 storage investments — comparison of R2050 and scenario variants.

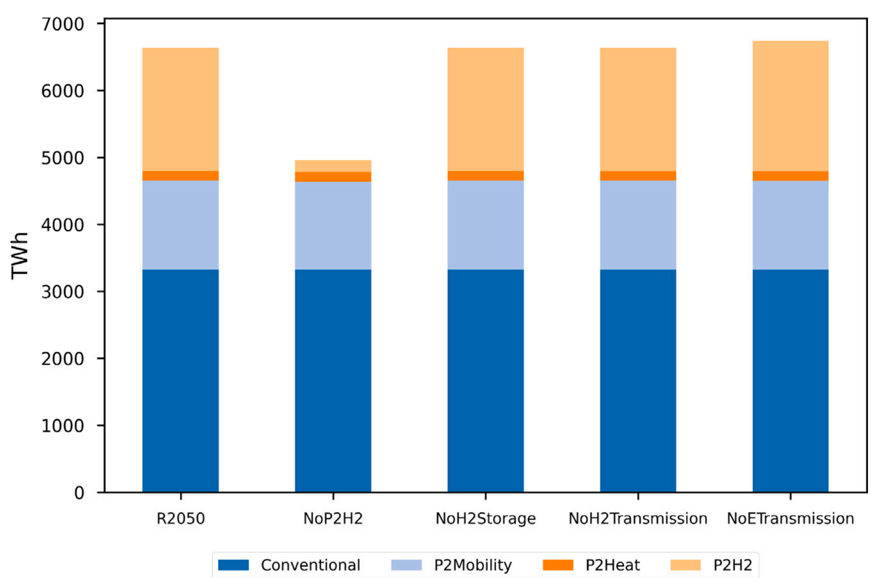

Fig. 20. EU electricity demand — comparison of R2050 and scenario variants.

NoH2Transmission scenarios (all around 6638 TWh); however, VRE production drops 0.5% (21 TWh) and 3% (140 TWh), respectively. This highlights how the ability of H_2 to follow VRE production, either in time or space, can help to increase VRE production by raising flexible H_2 electrification levels. In contrast, nuclear production increases by 5% (40 TWh) in NoH2Storage, indicating that nuclear energy may be a better alternative than VRE for electrifying more inflexible H_2. The differences in VRE and nuclear production affect the total system costs. For instance, Section 3.2.5 shows that the NoH2Storage and NoH2Transmission variants are around 10 bn€ and 4 bn€ more expensive than the reference scenario.

3.2.3. Energy transmission

Fig. 22 presents the required electrical and H_2 transmission results for the reference scenario (R2050) and its variants, along with their corresponding investment costs. Section 2.2 explains that COMPETES calculates the optimal transmission infrastructure needed to couple the demand and supply of electricity and H_2 among different countries.

In the R2050 case, the required H_2 transmission decreases significantly from 90 GW in the NoP2H2 scenario to 56 GW, which is expected since the model assumes unlimited SMR potential within each country. However, the total costs in this variant are the highest due to the required expansion of the electricity network. This decrease in H_2 transmission requirements is also driven by the lack of green H_2 production from countries with VRE resources, such as Spain and France.

In the NoH2storage scenario, the required expansion on the electricity network decreases by 6 GW compared to the R2050 case, while H_2 transmission increases by 72 GW. This reduces total costs compared to the R2050 case, as an extra investment in the electricity network is avoided, which is more costly (per GW) than expanding the H_2 network. Not allowing H_2 storage also results in increasing H_2 transmission capacity by 80%, which uses pipelines to store H_2 to be used in high-demand moments.

In the NoETransmission scenario, which only uses the future forecast of transfer capacities, the results show that only 5GW of extra investment in H_2 transmission is required. The associated energy transmission investment costs are reduced by 180% compared to the R2050 case.

In the NoH2Transmission scenario, where there is no possibility to invest in H_2 transmission and the expansion of the electricity network

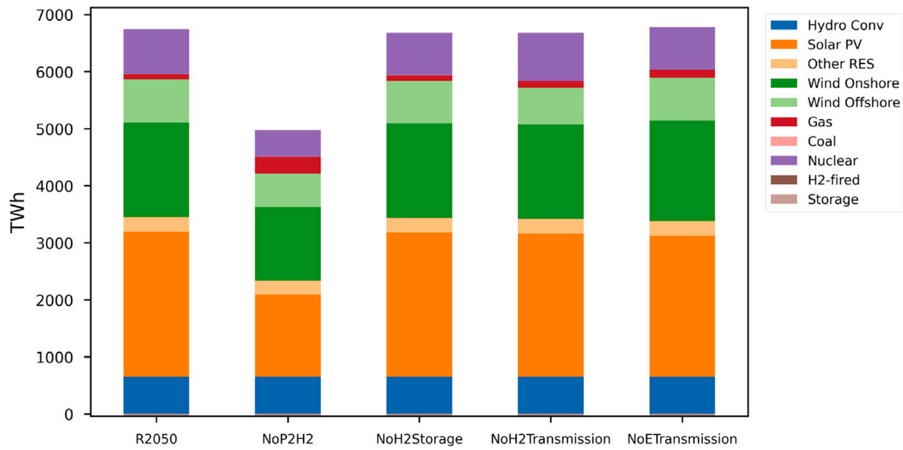

Fig. 21. EU electricity generation — comparison of R2050 and scenario variants.

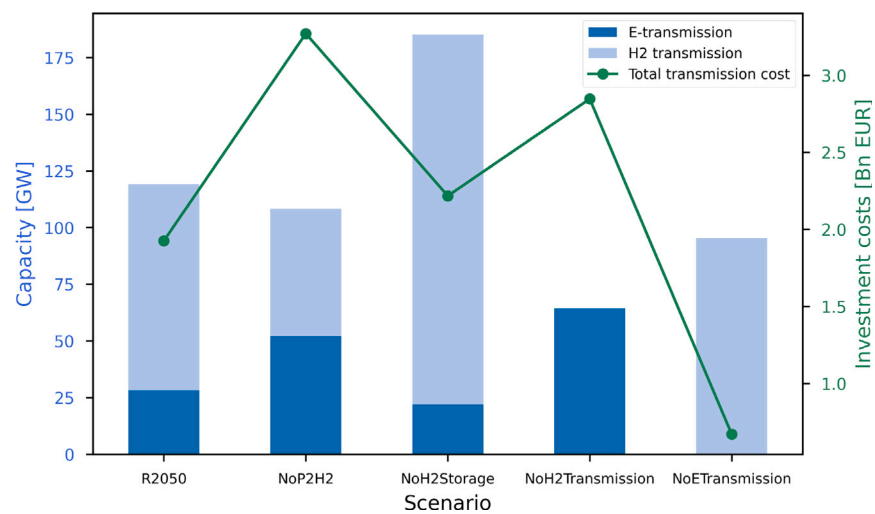

Fig. 22. EU transmission investments and costs comparison of R2050 and scenario variants.

is driven naturally, resulting in an increase in electrical network investments by 130% compared to the R2050 case. As shown in Fig. 17, this expansion in the electricity network is complemented by higher investment in H_2 storage.

3.2.4. CO_2 *emissions*

The results of the scenario variants regarding the CO_2 emissions in the EU electricity and H_2 sectors are presented in Fig. 23. The total CO_2 emissions increased by 19.5% and 20% in the NoH2Storage and NoH2Transmission cases, respectively, compared to the R2050 case. The increase in CO_2 emissions in the H_2 sector can be attributed to the rise in the use of SMR technologies to supply the H_2 demand in both cases.

Interestingly, CO_2 emissions are similar in the R2050 and the NoETransmission case. This suggests that further expanding the electricity network does not necessarily result in CO_2 emissions reductions after achieving a specific transfer capacity between countries.

3.2.5. *Total system costs*

Fig. 24 shows the system cost distributions for the R2050 scenario and variants. The R2050 scenario has the lowest total system costs, as it can access all investment options to achieve an optimal solution. It can minimise system costs by using the optimal combination of electrification, storage, and transmission. In contrast, the NoH2Storage case has the highest total system costs, about 3.4% (10.3 b€) higher than in the R2050 scenario. This is because the NewVRE costs, i.e., investment in wind and solar, are lower, while the variable H_2 costs increase due to the gas costs of H_2 production via SMR.

In the NoP2H2 scenario, costs are significantly shifted from investment in VRE to variable SMR costs. This is due to the lack of H_2 electrification, thus requiring less VRE capacity and higher gas consumption to produce H_2. Fig. 25 shows that the gas consumption in the NoP2H2 is around 2.4 times higher than the other scenarios. There is also an increase in gas-fired power plant output, resulting in a rise of 8.5 b€ in variable generation costs (fuel costs) shown in Fig. 24. Moreover, the NoETransmission scenario shows only a 0.3% total system cost increase compared to the R2050 scenario. In this case, there is a decrease in the variable VRE costs, but an increase in the conventional generation costs. Since the electricity network cannot expand further, it is not possible to integrate more VRE, so traditional generation is required.

3.2.6. *Electricity vs* H_2 *Transport*

In this section, we compare H_2 and electricity transport in terms of total system costs and CO_2 emissions; see Fig. 26. To this end, we analyse three transmission scenario variants: the R2050 reference scenario, the NoETransmission, and the NoH2Transmission extreme cases. The R2050 scenario represents the optimal tradeoff between electricity and H_2 transmission expansion; the NoETransmission scenario assumes that no further development of the electricity network is allowed; and the NoH2Transmission variant considers the absence of H_2 transport via pipelines.

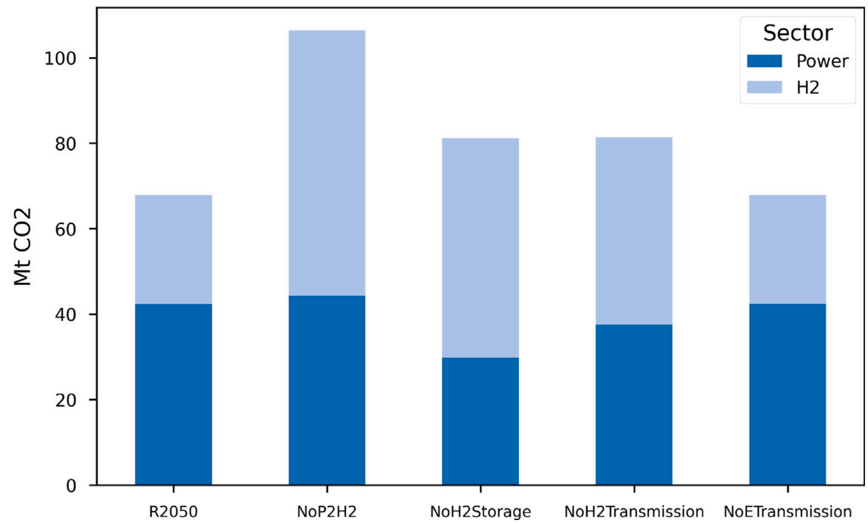

Fig. 23. EU CO_2 emissions — comparison of R2050 and scenario variants.

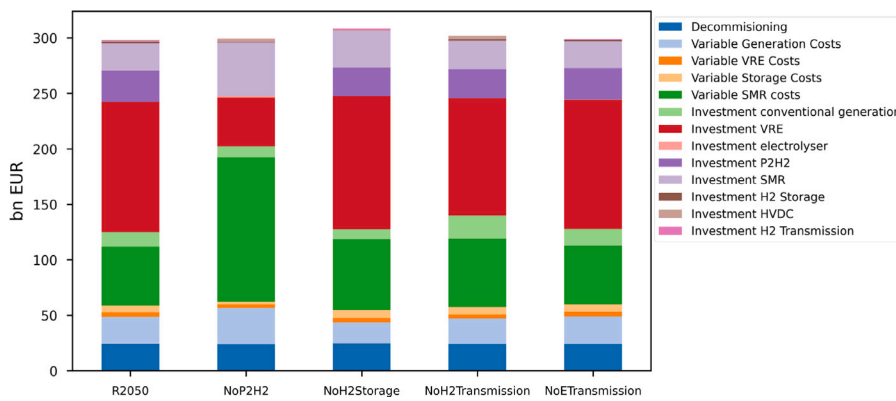

Fig. 24. EU total system costs — comparison of R2050 and scenario variants.

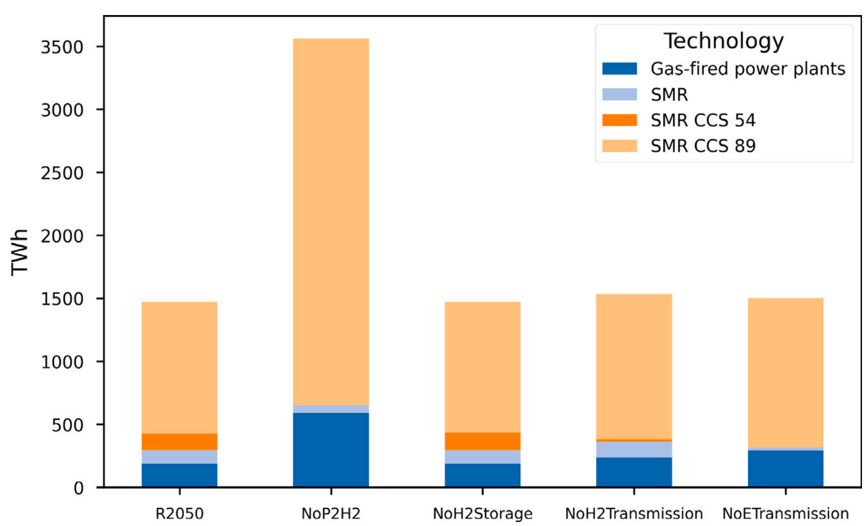

Fig. 25. EU total gas consumption — comparison of R2050 and scenario variants.

Our findings reveal that relying solely on electricity transmission, as in the NoH2Transmission scenario, leads to the worst outcome, resulting in higher costs and CO_2 emissions. Specifically, NoH2Transmission increases costs by 1.2% and emits around 20% more CO_2 compared to R2050. Conversely, the NoETransmission scenario has comparable CO_2 emissions to the optimal mix (R2050), but system costs are slightly higher (0.3%, 0.8 b€). Notably, investing solely in the H_2 network and storage eliminates the need for an additional 28 GW of electrical network expansion, as shown in Fig. 22. Our results indicate that a system with the expected transmission expansion by 2050 is already very

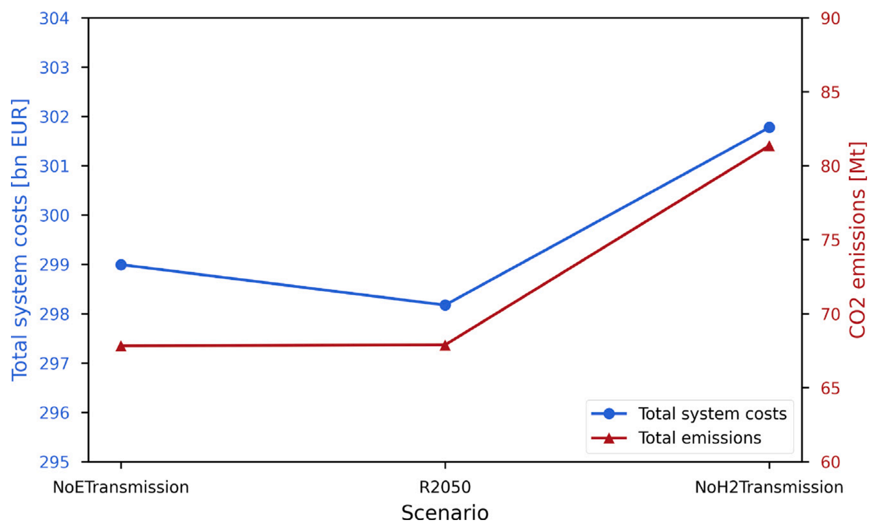

Fig. 26. H_2 vs. Electricity transmission.

close to the optimal solution. Therefore, to achieve more significant cost savings and CO_2 emissions reductions, we suggest policymakers should focus on facilitating H_2 transport through pipelines rather than increasing electricity transport.

3.3. Revisiting the research questions

This section has provided solutions to the research questions in Section 1.4. We summarise our findings as follows:

- *Is it possible to effectively include the retrofit of natural gas networks as an investment option in energy planning optimisation models? Yes–* The option of retrofitting natural gas networks as an investment option has been considered in COMPETES, according to the proposed formulation in Section 2.1. The formulation's effectiveness lies in its LP mathematical nature, allowing for solving large-scale optimisation models, like the European reference scenario and its variations, without a significant increase in the computational time burden.
- *What are the impacts on the total costs and CO_2 emissions of retrofitting the existing gas infrastructure for H_2 transport in the EU by 2050?* We can measure the impact by comparing the reference scenario (R2050) with its variants, particularly the scenario where no H_2 investment is made in retrofitting or new pipelines (NoH2Transmission). This results in a 1.2% increase in costs compared to R2050 and around 20% more CO_2 emissions.
- *How do investments in new electrolysers, hydrogen transmission, and storage infrastructure impact total CO_2 emissions compared to scenarios where these investments are not made?* We have created specific scenario variants to answer particular questions. For example, the NoP2H2 variant shows us the impact of not investing in new electrolysers. The NoH2Transmission variant shows the effect of not retrofitting or building new pipelines for H_2 transport, while the NoH2Storage variant focuses on H_2 storage. Lastly, the NoETransmission variant measures the impact of not having additional electricity transmission. To quantify the impacts, we compared the results of each variant to the reference scenario. For instance, the total CO_2 emissions increased by around 20% the NoH2Storage and NoH2Transmission cases compared to the R2050 case, highlighting the importance of the sector coupling between the power and hydrogen sectors to lower the total CO_2 emissions.

4. Conclusions

This paper has examined the potential of hydrogen (H_2) electrification to transform the power systems of the European Union in the year 2050. Various scenarios were used to measure the impact of essential investment decisions, such as electrolysers, storage, retrofitting, and new transmission systems. One key finding in our research is that a strategic balance of H_2 electrification and Steam Methane Reforming (SMR), alongside efficient transmission of both electricity and H_2, helps to reduce CO_2 emissions and enables a sustainable and cost-effective power system in the EU for 2050. Moreover, electrolysers might become essential tools in the power sector, providing flexibility to replace peak units like gas with non-polluting technologies. We, therefore, conclude that electrifying the H_2 production is essential to meet the European Union's goals of reducing long-term emissions.

The proposed formulation to consider retrofitting natural gas networks as an investment opportunity in COMPETES has offered valuable information. Without the option to transport H_2 through either retrofitting or new pipelines, there is a significant increase in costs and CO_2 emissions. Finding a balance between transporting H_2 and electricity is crucial to create an optimal system. The expansion of electricity transmission by 2050 is already near the optimal solution, so the focus should be on facilitating H_2 transport, including retrofitting.

In conclusion, the results in this paper provide a measurable assessment that can guide future policy decisions on this issue, and it is a valuable resource for policymakers to make informed decisions.

CRediT authorship contribution statement

Germán Morales-España: Methodology, Software. **Ricardo Hernández-Serna:** Data curation, Writing, Investigation. **Diego A. Tejada-Arango:** Visualization, Writing – reviewing & editing. **Marcel Weeda:** Supervision, Project administration.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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